International Journal of Greenhouse Gas Control 68 (2018) 112–127

Contents lists available at ScienceDirect

International Journal of Greenhouse Gas Control

journal homepage: www.elsevier.com/locate/ijggc

Designing an optimum carbon capture and transportation network by integrating ethanol distilleries with fossil-fuel processing plants in Brazil

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ARTICLE INFO

Keywords:
BECCS
Ethanol production
CO_2 transportation
Optimization
Brazil

ABSTRACT

Different long-term mitigation scenarios indicate carbon capture and storage associated with biomass (BECCS) might play a significant role in climate-change mitigation efforts, especially when it comes to long-term temperature stabilization. The ethanol fermentation process is considered as an early opportunity for BECCS deployment due to its low capture costs. Being a major ethanol producer, Brazil stands in a privileged position for the development of this technological option. However, previous scientific studies indicate several challenges for the deployment of a CO_2 transportation network in the country, mostly as a result of the associated seasonality of the sugarcane industry and consequent idleness observed in the carbon transportation infrastructure. To address those issues, this study developed and applied a methodology to design an optimum carbon network considering an alternative concept: the incorporation of new CO_2 emission sources aiming at guaranteeing adequate operational flows throughout the year, minimizing idleness and reducing transportation costs. Findings indicate that the incorporation of new CO_2 emission sources reduces transportation costs. The inclusion of CO_2 from both the cogeneration process and fossil sources results in an average levelized cost of transportation of 26 US$/t$CO_2$ (54% lower than transportation costs in the baseline case). However, this reduction in transportation costs does not compensate for the increase in capture costs, resulting in higher levelized abatement costs for the whole system. Indeed, cases including cogeneration have reached a levelized abatement cost of approximately 125 US $/t$CO_2$ (84% higher than in the baseline case). Nevertheless, by reducing transportation costs the strategy adopted in this study could facilitate the development of a carbon transportation network. Additionally, the integration of fossil-derived CO_2 has proved beneficial to the system, allowing improvements in flow regularity and reducing idleness problems related to the seasonality of biogenic sources.

1. Introduction

Carbon capture and storage associated with biomass (BECCS) is expected to play a significant role in climate-change mitigation in the future (IPCC, 2014; Kemper, 2015). Recent results from different Integrated Assessment Models (IAMs) around the world highlight the role BECCS might play in the energy sector, especially when considering the strictest scenarios in terms of carbon budget (Smith et al., 2016). As a matter of fact, the 450 ppm scenarios typically rely on BECCS (and the possibility of providing negative emissions) to deal with CO_2 concentration overshoot, especially in the second half of the century (IPCC, 2014; Kemper, 2015).

BECCS can be applied to various technologies with different levels of CO_2 emissions (EBTP, 2012; IEAGHG, 2011). CO_2 capture from ethanol fermentation is a commercially proven technology with low specific costs, and therefore ethanol production is regarded as an important opportunity for BECCS deployment (Carbo, 2011; Kemper, 2015; Reiter and Lindorfer, 2015). In fact, according to Kemper (2015), the majority of BECCS projects currently operational worldwide have ethanol production plants as the source of CO_2, and use the captured CO_2 for enhanced oil recovery (CO_2-EOR).

Abbreviation: CAESAR, Carbon and Energy Strategy Analysis for Refineries

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https://doi.org/10.1016/j.ijggc.2017.10.013
Received 11 May 2017; Received in revised form 29 September 2017; Accepted 23 October 2017
Available online 16 November 2017
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Nomenclature

List

EOR	Enhanced Oil Recovery
FCC	Fluid Catalytic Cracking Unit
HGU	Hydrogen Generation Unit
IECM	Integrated Environmental Control Model
NGCC	Natural Gas Combined Cycle
RECAP	Refinaria de Capuava
REDUC	Refinaria de Duque de Caxias
REPLAN	Refinaria de Paulínia
REVAPL	Refinaria Henrique Lage
RPBC	Refinaria Presidente Bernardes

In terms of carbon sinks, this study has chosen to work with enhanced oil recovery (CO_2-EOR) as a storage option[1] for two main reasons: (i) technological experience and data availability, since the oil and gas industry has been extensively studying the geological structure and physical properties of oil and gas fields, as well as predicting movement, displacement behavior and trapping of hydrocarbon in such sites (IPCC, 2005), and (ii) the potential economic benefits (revenues) from incremental oil production that puts EOR as a potential early option for carbon geological storage, especially being Brazil a large oil producer with mature oil fields already presenting high declining production rates (Ferreira, 2016).[2]

Brazil stands out as one of the major ethanol producers in the world. According to studies previously developed by Rochedo et al. (2016), Merschmann et al. (2016) and Silva et al. (2017), carbon capture from ethanol fermentation in Brazilian distilleries faces challenges for the deployment of the CO_2 transportation network due to disperse, small-scale distilleries (resulting in small volumes of CO_2 captured), and to the seasonable character of ethanol production. To address those limitations, this study considers the possibility of incorporating new CO_2 emission sources, in order to assure that the pipeline network functions with adequate operational flows throughout the year.

Co-processing of biomass with fossil fuels is considered a viable mitigation approach (Steinberg et al., 1993), as has been extensively discussed in the literature. Several articles address this mechanism and attempt to evaluate its development in combining biomass and fossil sources, mainly in energy-intensive industries such as oil refining and power generation (Lappas et al., 2009; Liu and Larson, 2014; Ng et al., 2015). In this perspective, this study proposes an innovative alternative since it considers biomass and fossil energy integration not at the point of the energy conversion, but in the downstream CO_2 transportation infrastructure.

The ethanol production is geographically concentrated in the Center-South region in Brazil, in the vicinity of the country's largest oil refineries and gas-fired power plants (potential new emission sources), and close to important oil and gas fields (suitable for carbon storage and enhanced oil recovery − EOR). Hence, through the inclusion of fossil-derived CO_2, this study aims to increase the total volume of transported CO_2 and to optimize the use of the pipeline network, minimizing idleness and reducing transportation costs. As the carbon capture from fossil-fuel processing facilities is more expensive than from ethanol production facilities, this study tests if the inclusion of fossil-fuel units in the carbon capture and transportation network leads to a cost reduction in the transportation network that more than compensates the increase in carbon capture costs, which are typically higher in those kinds of installations.

Fig. 1 provides the location of existing ethanol distilleries and suitable alternative emission sources (nearby oil refineries and fossil-fuel power plants), as well as oil and gas fields, suitable for carbon storage and enhanced oil recovery (CO_2-EOR).

It is also worth noting that the importance of improving CO_2 flow regularity is associated with two main objectives: guaranteeing capital expenditure recovery and adjusting the CO_2 mass flow to EOR operation characteristics. Firstly, from a capital expenditure perspective, capital costs in carbon capture, transportation and storage systems are a critical factor for the large scale deployment of these systems (Tapia et al., 2015). Furthermore, from the EOR operation characteristics perspective, there are various studies available in the scientific literature working with the assumption of a constant injection rate for CO_2-EOR operations (Choi et al., 2013; Abedini, 2014; Mazzetti et al., 2014; Brownsort, 2015; Tapia et al., 2015; Tapia et al., 2016). Therefore, improving flow regularity, through the reduction of seasonality issues related to the sugarcane industry, is important for correctly adjusting the CO_2 flow to the characteristics of the EOR operations.

This study is structured as follows. Section 2 presents the methodological procedure developed and applied in this study. Section 3 presents the case studies, detailing the results of the different scenarios of carbon capture according to the kinds of emission sources included in the carbon transportation network. Section 4 discusses and compares these results in terms of abatement costs and abatement potentials. Finally, Section 5 provides final remarks, with main achievements and future work suggestions.

2. Methodology

In order to evaluate the optimum carbon transportation network design through the integration of new emission sources (other than the ethanol fermentation process), this study followed four basic steps: (i) mapping the distilleries, (ii) selecting nearby potential emission sources, (iii) estimating CO_2 availability and capture costs related to the selected new emission sources, and (iv) calculating the total abatement costs for each of the stablished scenarios (including both capture and transportation costs) (see Fig. 2).

2.1. Mapping existing distilleries

All 236 selected ethanol distilleries in the Center-South region of Brazil were mapped using the ArcMap 10.1 software. Following the path led by the work previously conducted by the same authors in Silva et al. (2017), the selection criteria intended to exclude plants considered isolated (without at least 10 other plants around a 100 km radius) in order to avoid long-distance pipes operating with low capacity.

2.2. Selecting new emission sources

New emission sources were selected according to their proximity

[1] Even though there is evidence of suitable aquifer storage beneath the State of São Paulo (Moreira et al., 2016), there are several issues concerning this storage option, including (i) geological uncertainty, with limited seismic and well data available (unlike data on oil and gas reservoirs), (ii) lack of industry experience (unlike the vast experience shared in the oil and gas industry for EOR), (iii) difficulties in assessing CO_2 storage capacity in deep saline formations, and (iv) difficulties in assessing risks of leakage (which could result in groundwater contamination, impacting wildlife habitats and restricting or eliminating agricultural use of land) (IPCC, 2005). Therefore, this option has not been contemplated by this study. However, this study acknowledges the need to include such storage options in future studies, since they could be an important opportunity to reduce costs of transportation.

[2] Even though we cannot consider EOR operations to be widespread in Brazil, it is fair to say that Petrobras, the Brazilian oil company, has some experience with these operations, including thermal, chemical and miscible recovery processes. In what regards CO_2-EOR (miscible process), Petrobras has accounted for 3 pilot projects from which one has been successfully implemented and two have been interrupted mostly due to problems with the supply of CO_2. Nowadays, Petrobras is working with WAG-EOR (alternate injection of water and gas − in this case CO_2) in the pre-salt Lula field. Preliminary results have been promising so far, according to the company (Petrobras, 2017).

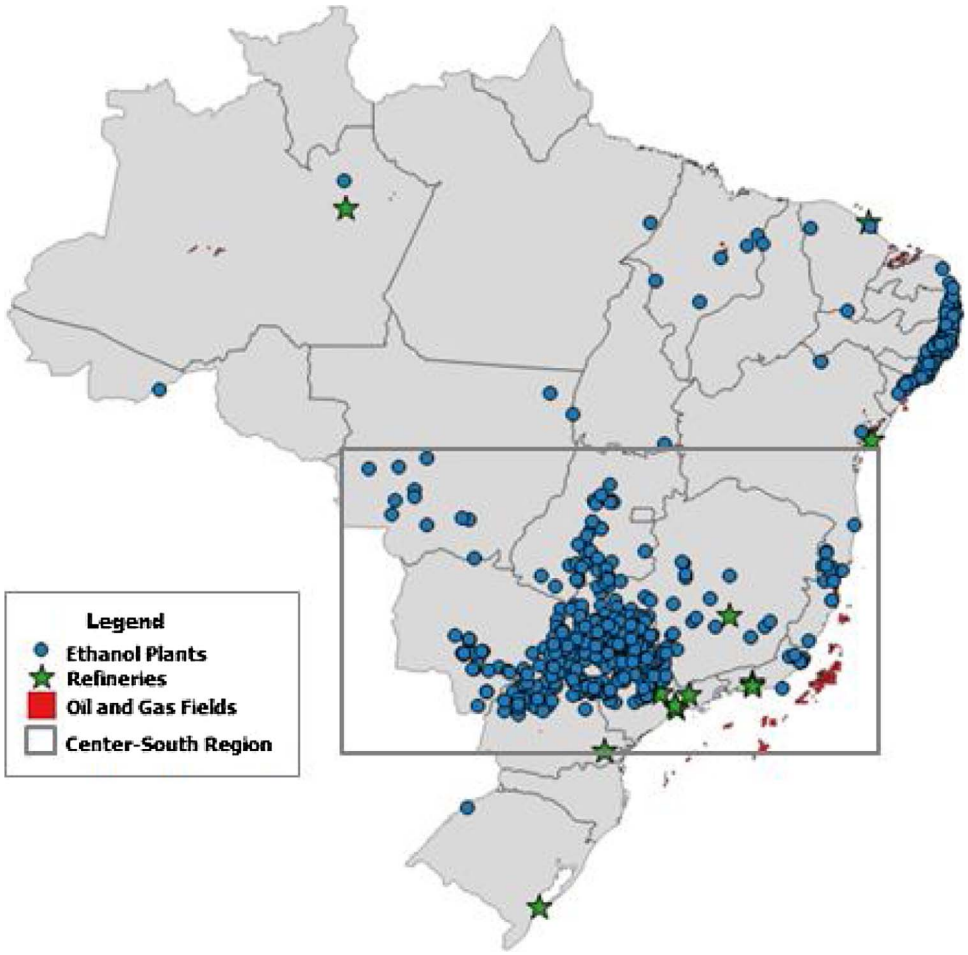

Fig. 1. Location of distilleries, oil refineries, and oil and gas fields in Brazil.

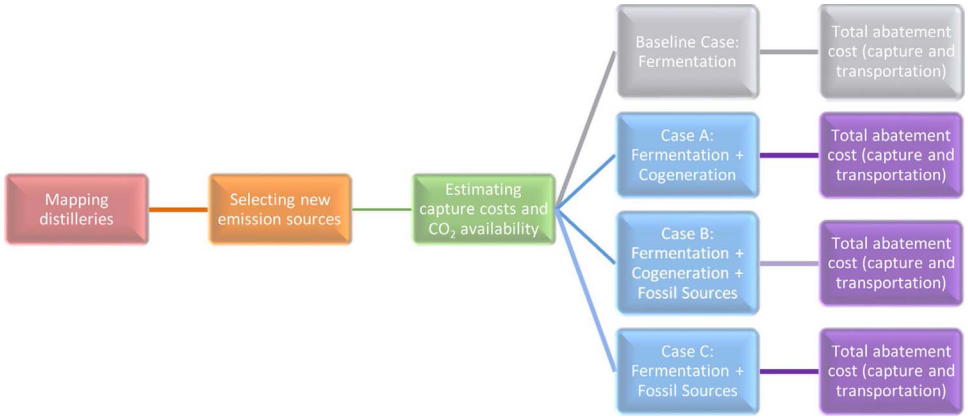
Mapping distilleries
Selecting new emission sources
Estimating capture costs and CO_2 availability
Baseline Case: Fermentation
Case A: Fermentation + Cogeneration
Case B: Fermentation + Cogeneration + Fossil Sources
Case C: Fermentation + Fossil Sources
Total abatement cost (capture and transportation)
Total abatement cost (capture and transportation)
Total abatement cost (capture and transportation)
Total abatement cost (capture and transportation)

Fig. 2. Methodological scheme of the CO_2 capture and transportation network design.

towards the mapped distilleries and stablished carbon transportation network (Fig. 3). The chosen new sources are presented in Table 1, and include cogeneration units using bagasse as feedstock in distilleries, fluid catalytic cracking (FCC) units and hydrogen generation units (HGUs) in oil refineries, and a natural-gas combined cycle (NGCC) power plant.[3]

[3] This study assumes that carbon capture equipped-power plants would operate to match the base load. This derives both from the need to recover the capital cost of the carbon capture facility and the technical constrains of the carbon capture facility, which should not operate under fast ramp-ups or ramp-downs.

2.3. Estimating CO_2 availability and capture costs

2.3.1. Fermentation process in distilleries

Estimation of CO_2 availability and costs of capture related to the fermentation process in distilleries producing ethanol in Brazil follows the methodological procedure and the results presented in Silva et al. (2017), a study previously conducted by this same group of authors. For the "Baseline Case", the carbon network was optimized using the method of locating one single hub to collect the CO_2 captured from ethanol production facilities according to the Kernel Density Estimation (KDE), which is a spatial data analysis technique. In this case, only CO_2 from glucose fermentation was evaluated. For further details on the methodology and the "Baseline Case", see Silva et al. (2017).

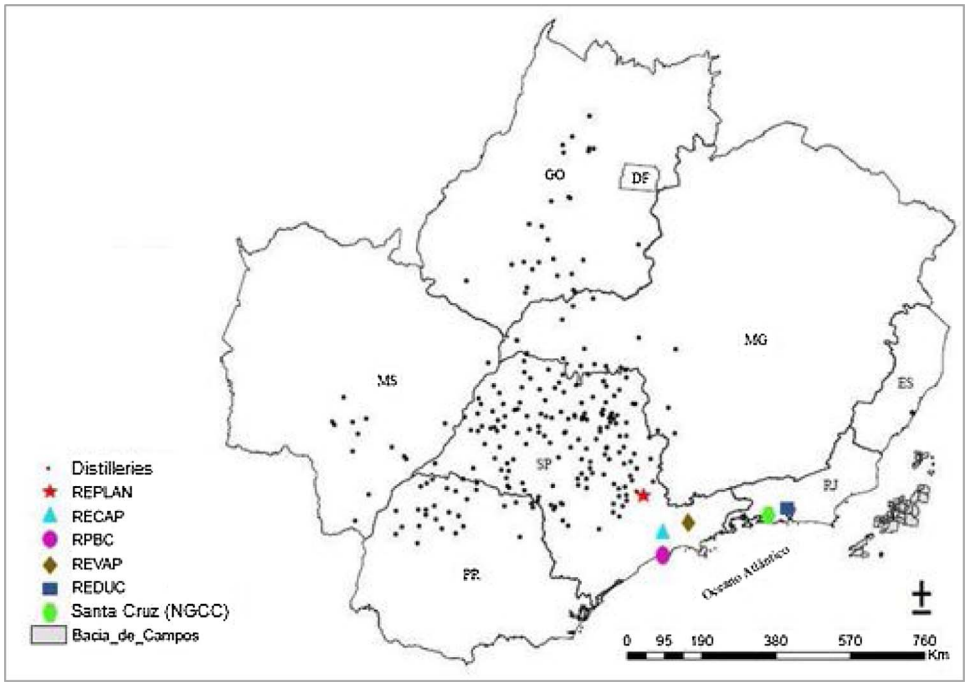

Fig. 3. Location of selected distilleries and new emission sources in the Center-South Brazil.
Note: REPLAN, RECAP, RPBC, REVAP and REDUC are oil refineries. Santa Cruz is a combined cycle, natural gas power plant.

Table 1
Selected new CO_2 emission sources.

Source	Unit
Cogeneration units using bagasse in distilleries (COGEN)	Selected Distilleries [a](236 distilleries)
Fluid Catalytic Craking (FCC) Units and Hydrogen Generation Units (HGUs) in oil refineries	Refinaria de Paulínia (REPLAN) Refinaria Duque de Caxias (REDUC) Refinaria Henrique Lage (REVAP) Refinaria de Capuava (RECAP) Refinaria Presidente Bernardes (RPBC)
Natural Gas Combined Cycle Power Plants (NGCC)	Santa Cruz Power Plant

[a] The complete list of selected distilleries is available in the suplementary material, and includes the same group of distilleries previously evaluated by the authors in Silva et al. (2017).

2.3.2. Cogeneration systems in distilleries

Bagasse consists of a lignocellulosic material resulting from the sugarcane juice extraction during the process of ethanol and/or sugar production. In the sugarcane industry, cogeneration systems use bagasse combustion in order to meet final energy demands of the productive units, supplying heat and power throughout the process (Khatiwada et al., 2016). Even though bagasse use for cogeneration in distilleries might also face the challenge of seasonable availability,[4] this source was selected due to the large CO_2 emission potentials associated with bagasse combustion.

This study conducted the simulation of a typical cogeneration unit using the IECM (Integrated Environmental Control Model)[5] software. Simulation was divided in two fronts: without carbon capture (for reference), and with carbon capture (main interest of this study). As the IECM software was designed to work with thermal power plants using coal or natural gas as feedstocks, it was necessary to adapt the feedstock characteristics entry to run a simulation using sugarcane bagasse. Feedstock properties were customized according to Table 2.

Capture costs were calculated according to Eq. (1).

$$C_{COG} = \frac{CE_{Cap} - CE_{Ref}}{CC_{Ref} - CC_{Cap}} \quad (1)$$

where C_{COG} represents capture costs associated with the cogeneration system (US$/tCO$_2$); CE_{Cap} is the cost of electricity with carbon capture (US$/MWh); CE_{Ref} is the cost of electricity in the reference plant (US $/MWh); CC_{Cap} is the amount of CO_2 captured in the plant with carbon capture (tCO$_2$/MWh); and CC_{Ref} is the amount of CO_2 captured in the reference plant (tCO$_2$/MWh) (Table 3).

Total bagasse production was estimated through Eq. (2), accounting for both ethanol and sugar production.[6] Table 4 presents the parameters used in the calculations.

$$BP_i = \frac{1}{R_{AE}} * \frac{1}{R_E} * \left(F_B * P_{E_i} * 10^3\right) \quad (2)$$

where BP_i is the annual bagasse production of the *i*th distillery (t/yr); R_{AE} represents the proportion of sugarcane directed to ethanol production; R_E represents the amount of ethanol produced per mass of sugarcane crushed (liters of ethanol/t sugarcane); F_B represents the proportion of bagasse produced per mass of sugarcane crushed (t bagasse/t sugarcane); and P_{Ei} is the annual ethanol production of the *i*th distillery (m^3/yr).

[4] It is interesting to notice that there is a possibility for sugarcane bagasse storage in order to deal with the challenges imposed by its seasonable character. However, due to the action of decomposing fungi, storage incurs in severe losses in the material's calorific value, leading to approximately 30% losses for storage periods of up to 150 days (off-season period) (Santos et al., 2011).

[5] The Integrated Environmental Control Model (IECM), IECM®, was developed by the Center for Energy and Environmental Studies at the Carnegie Mellon University for the US Department of Energy's National Energy Technology Laboratory (DOE/NETL) (IECM, 2017). It is a computer modelling software that analyses costs and performance of emission control equipments in thermal power plants. The program allows users to configure the plant to be modelled from different technologies, such as pollution control and carbon capture. This study applied version 9.2.1.

[6] There are two different types of distilleries in Brazil: autonomous distilleries, where production is fully oriented towards ethanol production, and annex distilleries, where there are processing units to produce both ethanol and sugar.

Table 2
Sugarcane-bagasse properties.
Source: PNUD (2005).

Composition	Dry Basis (wt.%)	Wet Basis – 50% (wt.%)
Carbon (C)	44.60	22.30
Hydrogen (H)	5.80	2.90
Oxygen (O)	44.50	22.25
Nitrogen (N)	0.60	0.30
Sulfur (S)	0.10	0.05
Chlorine (Cl)	0.02	0.01
Ashes	2.20	1.10
Others	2.18	1.09
Water (H_2O)	–	50.00
Higher Heating Value (HHV)	18.10 MJ/kg	9.05 MJ/kg

Table 3
Parameters used in the cogeneration unit simulation.

Parameter	First Run (Without Carbon Capture)	Second Run (With Carbon Capture)
Environment Temperature (°C)	24	24
Plant life (years)	25	25
Discount rate (%) [a]	10	10
Operating labor rate (US $/h) [b]	12.38	12.38
Capacity factor (%) [c]	50	50
Boiler efficiency (%) [d]	80	80
Excess air (%)	30	30
Power output (MW) [e]	40	40
CO_2 capture system	–	Econamine FG+
Efficiency of CO_2 removal (%)	–	90

[a] In accordance with Khatiwada et al. (2016).
[b] Adapted for Brazil according to the *Bureau of Labor Statistics, U.S. Department of Labor* (BLS, 2015).
[c] Stablished according to the analysis of the historic period data for installed capacity and bioelectricity generation in Brazil, according to EPE (2015) and Unica (2016).
[d] According to Nova Cana (2016).
[e] Typical installed power for cogeneration units in Brazil, according to Nova Cana (2016).

Table 4
Parameters for the estimation of total bagasse production per distillery.

Parameter	Autonomous Distillery Ethanol	Annex Distillery Ethanol + Sugar
Proportion of sugarcane directed to ethanol production (wet basis) (R_{AE}) [a]	1.00	0.55
Ethanol produced per metric tonne of sugarcane crushed (liter of ethanol/t sugarcane) [b]	73.03	73.03
Proportion of bagasse per sugarcane crushed (t bagasse/t sugarcane) [c]	0.244	0.244

[a] According to *Anuário Estatístico de Agroenergia* (MAPA, 2015).
[b] According to *Anuário Estatístico de Agroenergia* (MAPA, 2015).
[c] Average value for Center-South Brazil, according to *Companhia Nacional de Abastecimento* (CONAB, 2011).

Total bagasse production was estimated considering all selected distilleries, through the sum of bagasse production for each distillery individually. Total CO_2 captured from cogeneration was determined according to Eq. (3). Carbon capture efficiency is set as 90%. The emission factor related to bagasse combustion is 780 kg CO_2 per metric tonne of bagasse (EPA, 2009).

$$CO_2\text{Captured(COG)} = \eta_{COGEN} * F_E * \text{Total BagasseProduction} \quad (3)$$

where "CO_2 Captured (COG)" is the total amount of CO_2 captured in cogeneration (tCO_2/yr); η_{COGEN} is the carbon capture efficiency related to cogeneration systems; F_E is the emission factor related to bagasse combustion ($kgCO_2$/t bagasse) and "Total Bagasse Production" is the annual production of bagasse considering all selected distilleries (t bagasse/yr).

2.3.3. FCC units and HGUs in oil refineries

The two main sources of CO_2 emissions in Brazilian oil refineries with potential for carbon capture at relatively low costs are the fluid catalytic cracking (FCC) units and the hydrogen generation units (HGUs) (Rochedo et al., 2016). Emissions from FCC units are derived from deposited coke burning during catalyst regeneration, resulting in high CO_2 concentrated gas streams. In this case, carbon capture technology used is oxy-combustion (Szklo et al., 2012). Emissions from HGUs are derived from concentrated exhaust that leaves the reformer, and the carbon capture technology used is post-combustion via chemical absorption (Lindsay et al., 2009).

Capture costs related to such units were stablished according to Rochedo et al. (2016) and Lindsay et al. (2009). To estimate CO_2 emissions from these units, this study used the Carbon and Energy Strategy Analysis for Refineries (CAESAR) tool[7] to determine annual fuel consumption per process unit related to the selected Brazilian oil refineries. Maximum nominal capacities and capacity factors used are presented in Table 5, and were determined according to Guedes (2015) and Szklo et al. (2012).

Total CO_2 captured in each refinery was determined according to Eq. (4). Carbon capture efficiency for oxy-combustion systems in FCC units was considered 100% (> 99.9%) (Mello et al., 2009). Carbon capture efficiency for post-combustion systems in HGUs was considered 70% (Lindsay et al., 2009). The emission factor for FCC coke burning is 97.5 tCO_2/TJ and the emission factor for natural gas burning is 56.1 tCO_2/TJ, according to data from the Intergovernmental Panel on Climate Change (IPCC, 2006).

$$CO_2\text{Captured(OilRefineries)} = \eta * F_E * C_i \quad (4)$$

where "CO_2 Captured (Oil Refineries)" is the annual amount of CO_2 captured (FCC or HGU) (tCO_2/yr) for the *i*th refinery; η is the carbon capture efficiency (FCC or HGU); F_E is the emission factor related to fuel consumption (coke or natural gas) (tCO_2/TJ); and Ci is the annual fuel consumption for the *i*th refinery (coke or natural gas) (TJ/yr).

2.3.4. Power plant

According to the Brazilian National Agency for Electrical Energy (*Agência Nacional de Energia Elétrica* – ANEEL), the Santa Cruz Power Plant holds a granted gross power of 350 MW. This study used the IECM software for the simulation of the power plant in two fronts: without carbon capture (for reference) and with carbon capture. Capture costs and total CO_2 captured resulted directly from the simulations. Data related to the composition of natural gas are presented in Table 6. Other parameters used for the configuration of the plant are presented in Table 7.

2.4. Estimating total abatement costs

Besides the Baseline Case, this study evaluated three different cases (or scenarios). In "Case A", it considered carbon capture from 236 distilleries in Brazil, accounting for both the fermentation process for ethanol production and the cogeneration systems (therefore, "Case A" includes only biogenic sources of CO_2, but differs from the Baseline case by adding the CO_2 emitted from bagasse burning). In "Case B", in addition to carbon capture in distilleries (fermentation and cogeneration), it considered carbon capture from fossil-fuel sources, such as oil

[7] CAESAR is a simulation tool developed for Brazilian oil refineries (Guedes, 2015) and subsquently applied to the world oil refining system (Rochedo, 2016).

Table 5
Maximum nominal capacities for FCC units and HGUs.

Refinery	FCC Max Nominal Capacity (m^3/d)	FCC Capacity Factor	HGU Max Nominal Capacity (m^3/d)	HGU Capacity Factor
REPLAN	16000	0.90	3750000	0.55
REDUC	7500	0.78	2267000	0.55
REVAP	14000	0.73	1630000	0.70
RECAP	3100	0.90	550000	0.90
RPBC	10000	0.60	2870000	0.50

Table 6
Natural Gas Composition.
Source: GASNET (2016).

Composition	(vol.%)
CH_4	88.56
C_2H_6	9.17
C_3H_8	0.42
CO_2	0.65
N_2	1.20

Table 7
Parameters used in the power plant simulation.

Parameter	First Run (without Carbon Capture)	Second Run (with Carbon Capture)
Environment Temperature (°C)	24	24
Plant life (yr)	30	30
Discount rate (%) [a]	10	10
Operating labor rate (US$/h) [b]	12.38	12.38
Capacity factor (%) [c]	75	75
Natural gas price (US$/$10^3 m^3$) [d]	445.00	445.00
Gas turbine adiabatic efficiency (%)	85	85
Gross power – 2× GT (MW)	350	350
CO_2 capture system	–	Econamine FG +
CO_2 removal efficiency (%)	–	90

[a] In accordance with other simulations conducted by this study.
[b] Adapted for Brazil according to the Bureau of Labor Statistics (BLS, 2015).
[c] According to data provided by FURNAS Sustainability Reports (2010–2014) (FURNAS, 2015).
[d] According to the Natural Gas Industry Monthly Report for January 2016, provided by the Brazilian Ministry of Mines and Energy (*Ministério de Minas e Energia*) (MME, 2016).

refineries and power plant. In "Case C", it considered carbon capture from the fermentation process in distilleries and from fossil-fuel sources, excluding bagasse-fired cogeneration systems. Finally, it takes for reference the "Baseline Case" (which evaluates carbon capture from the fermentation process alone), following results obtained in Silva et al. (2017). The method used for estimating the levelized abatement costs (including both capture and transportations costs) follows the procedure previously stablished by Merschmann et al. (2016) and Silva et al. (2017). Main steps are described below. Main parameters are given in Table 8. All monetary values were updated to 2015 by the Chemical Engineering Plant Cost Index – CEPCI (Chemical Engineering, 2016).

Step 1: Calculating the levelized costs of capture

- Distilleries

The levelized costs of capture including the fermentation process and the cogeneration system in distilleries are determined according to Eq. (5). "Case A" and "Case B" include carbon capture in both fermentation and cogeneration. However, "Case C" considers only carbon capture in the fermentation process. Therefore, exceptionally in this case parameter "C_{COG}" (which represents cost of capture related to the cogeneration system) is equal to zero.

Table 8
Standard parameters values.

Parameter	Value	Source
Dehydration and compression costs	US$ 11.00/tCO_2	Dahowski and Dooley (2008), Bonijoly et al. (2009), Milmo (2010)
Electricity price (PE)	US$ 55.64/MWh	(EPE, 2016)
Operation and maintenance costs (O&M)	3.5% of total investment costs	Van den Broek et al. (2010)
Pipeline project lifetime (n)	40 years	Van den Broek et al. (2010)
Discount rate (i)	10% per year	Khatiwada et al. (2016)
Exchange rate	US$ 1.00 = R$ 3.81 = € 0.91	BCB (2016)

$$C_{c,d} = \left(\frac{C_F + C_{COG}}{M_{CO_2}} \right) \quad (5)$$

where $C_{c,d}$ is the levelized cost of capture in distilleries (US$/$tCO_2$); C_F represents the annual costs of capture related to the fermentation process (costs for dehydration and compression of CO_2) (US$); C_{COG} represents the annual costs of capture related to the cogeneration systems (US$); and M_{CO_2} is the total amount of CO_2 captured in a year (tCO_2).

- Fossil-fuel sources

The levelized costs of capture related to the selected fossil sources (oil refineries and power plant) were calculated according to Eq. (6).

$$C_{c,f} = \left(\frac{\sum C^i_{c,j} \cdot M^i_{CO2_j}}{M_{CO_2}} \right) \quad (6)$$

where $C_{c,f}$ is the levelized cost of capture related to the fossil-fuel sources (oil refineries and power plant) (US$/$tCO_2$); $C^i_{c,j}$ represents the cost of capture of process "j" at the oil refinery or power plant "i" (US $/$tCO_2$); $M^i_{CO2_j}$ represents the annual amount of CO_2 emissions from process "j" at the oil refinery or power plant "i" (tCO_2/yr); and M_{CO_2} represents the total amount of CO_2 captured from fossil-fuel sources (including oil refineries and power plant) in a year (tCO_2).

Step 2: Calculating the levelized costs of carbon transportation

The levelized costs of carbon transportation related to the pipeline network are determined according to Eq. (7).

$$LC_T = \left(\frac{I \times CRF + O\&M + VC}{M_{CO_2}} \right) \quad (7)$$

where LC_T is the levelized cost of carbon transportation via pipeline network (US$/$tCO_2$); I represents the investment costs (US$); CRF is the capital recovery factor (yr^{-1}); O&M represents operation and maintenance costs (US$/yr); VC represents the variable costs (US$/yr); and M_{CO_2} is the annual amount of transported CO_2 (tCO_2/yr).

- Investment costs (I)

Investment costs were determined by the selection of the lower cost configuration obtained for the pipeline network, using the ArcMap 10.1 software. Such selection was based in the confrontation of results from Eq. (8) (Van den Broek et al., 2013), regarding different sections of the pipeline network.

Table 9
Pipeline cost factors for investment costs estimation.
Source: Merschmann et al. (2016).

Slope (degrees)	**Fs_i**
< 6	1.0
6–11	1.1
11–17	1.3
17–35	3.0
> 35	9.0
The cell corresponds to an	**Fc_i** [1]
Offshore area	3.0
Onshore area where there already is a pipeline	0.9
Onshore area where there is no pipeline	1.0
The cell corresponds to a/an	**Flu_i**
Area that contains a (or part of a) conservation unit (protected area or indigenous land)	25.5
Area that is crossed by a body of water	4.0
Urban area	1.8
Rural area	1.0
Do any roads or railways cross the cell?	**Fci** $_i$
Yes	3.0
No	1.0

$$I = Bc*D*\sum_{i=1}^{n} Fc_i*Fs_i*[Flu_i*(1 - 0.1*N_i) + 0.1*N_i*Fci_i]*L_i \quad (8)$$

where Bc is the standard pipeline cost factor; D is the diameter of the pipeline section; Fc_i is the factor associated with the presence of a pipeline corridor in cell i; Fs_i is the factor associated with the slope in the terrain in cell i; $Flu_i$is the factor associated with land use in cell i; $N_i$is the number of roads or railways crossing cell "i"; $Fci_i$is the factor associated with the passage of roads or railways in cell i; and $L_i$is the length of the pipeline that crosses cell i.

Factor $Fc_i$is used to demonstrate that offshore pipeline construction costs are superior when compared to onshore pipeline construction costs. Additionally, it indicates that the construction of pipelines in existing pipeline areas is cheaper than the construction of pipelines in areas where there are no pipelines installed. Factor Fs_i is used to demonstrate that pipeline construction costs are proportional to the inclination of the terrain, since pipeline installation in steep lands is more expensive. Factor Flu_i regards land use issues which influence the pipeline installation costs, such as environmentally protected areas and indigenous areas, rural and urban areas, among others. Factor $Fci_i$is related to the passage of roads or railways, since such constructions increase the pipeline installation costs (Van den Broek et al., 2013). Parameter Bc represents the cost of a one meter length and one meter diameter pipe crossing a cell in onshore rural areas where there are no pipeline corridors, the terrain is plain, and there are no roads or railways. Finally, L_i and D represent the pipeline length and diameter, respectively.

Given all the described factors, the ArcMap 10.1 software is used to select the lowest-cost arrangement for each section of the pipeline, assuming a constant diameter. Typical values for each of the factors are presented in Table 9.

Pipeline diameters were determined according the CO_2 flow, as shown in Eq. (9). Parameters used are presented in Table 10.

$$D = \left(\frac{32*f*m^2*L}{\pi^2*\rho*\Delta P}\right)^{\frac{1}{5}} \quad (9)$$

where f is the fanning friction factor; m is the CO_2 mass flow ($kgCO_2/s$); $\frac{\Delta P}{L}$ is the pressure drop in the pipeline (Pa/m); and ρis the CO_2 density (kg/m^3).

To meet flow variations along the year, mass flow (m) represents the maximum CO_2 supply (or peaks in production) for which pipelines should operate at full capacity. August was the month with the highest share of the annual ethanol production observed in the period: around 15% of the season's production (MAPA, 2015; Unica, 2016). In this context, the pipes were designed to transport, in a monthly basis, 15% of the CO_2 supply, assuming that plants operate 24 h a day during harvest.

Table 10
Parameters used in pipeline diameter calculation.
Source: Merschmann et al. (2016).

Parameter	Constant values
f [a]	3.75×10^{-3}
ΔP/L (Pa/m)	20
ρ (kg/m^3) [b]	800

[a] Fanning friction factor is an dimensionless number used in fluid flow calculations. According to Knoope et al. (2013), pressure drop in a duct must be 20 Pa/m.
[b] Parameter ρ represents the average density of CO_2 in a pressure between 8 and 11 MPa.

The standard cost factor (Bc) estimation was based on typical construction costs of natural gas pipeline networks in Brazil, representing the minimum costs for a pipeline section. The estimated value was 835 US$/$m^2$, according to EPE (2014). Values were updated according to the Chemical Engineering Plant Cost Index – CEPCI (Chemical Engineering, 2016).

The transportation network was designed using ArcMap 10.1. The information regarding physical and environmental aspects in the pathway of the pipeline network was mapped and used to support investment costs computation. Least-cost routes for the connection of each distillery to the hub were assessed using Cost Distance, Cost Backlink and Cost Path tools in ArcMap 10.1. The Cost Path tool transformed the results obtained from Cost Distance and Cost Backlink into maps connecting emission sources (distilleries, refineries and power plant) to the sink. The network configurations varied depending on the assessed cases, as will be further explained.

In "Case A", the pipeline network design was based on the following steps. Taking into account the 236 distilleries previously selected and mapped, the Kernel Map tool was used to determine the hub location. The hub was positioned to meet the maximum concentration of CO_2 emissions. Tools Cost Distance, Cost Backlink and Cost Path were used to calculate the investment costs for connecting each distillery to the hub, and the hub to the Parati Oil Field (identified in this case as the sedimentary basin to store the captured CO_2).

In "Case B" and "Case C", fossil-fuel emission sources were included. Therefore, in order to take advantage of the economies of scale associated with the increased pipeline capacity, the pipeline network design was based on the following steps. Given that Brazil's biggest oil refinery REPLAN is located at similar latitude as the Campos oil field, and that most of the selected distilleries are located north or west of the REPLAN refinery, this study chose to connect some of the distilleries directly to REPLAN (while others would be first connected to the hub). Using the Cost Path ArcMap tool, out of the 236 selected distilleries 190 distilleries were connected to the hub, while the remaining 46 distilleries were directly connected to REPLAN (Fig. 4). Fossil sources were connected as follows. REPLAN was connected to REVAP. RPBC was connected to RECAP, and RECAP was connected to REVAP. Then, REVAP was connected to the Santa Cruz Power Plant, which was connected to REDUC. Finally, REDUC was connected to the Pitangola oil field, identified as the sedimentary basin to store the captured CO_2 (Fig. 5). Investment costs for each connecting path were calculated using the same tools described in "Case A".

The investment in recompression stations was calculated using Eq. (10) (IEAGHG, 2013; Knoope et al., 2013).

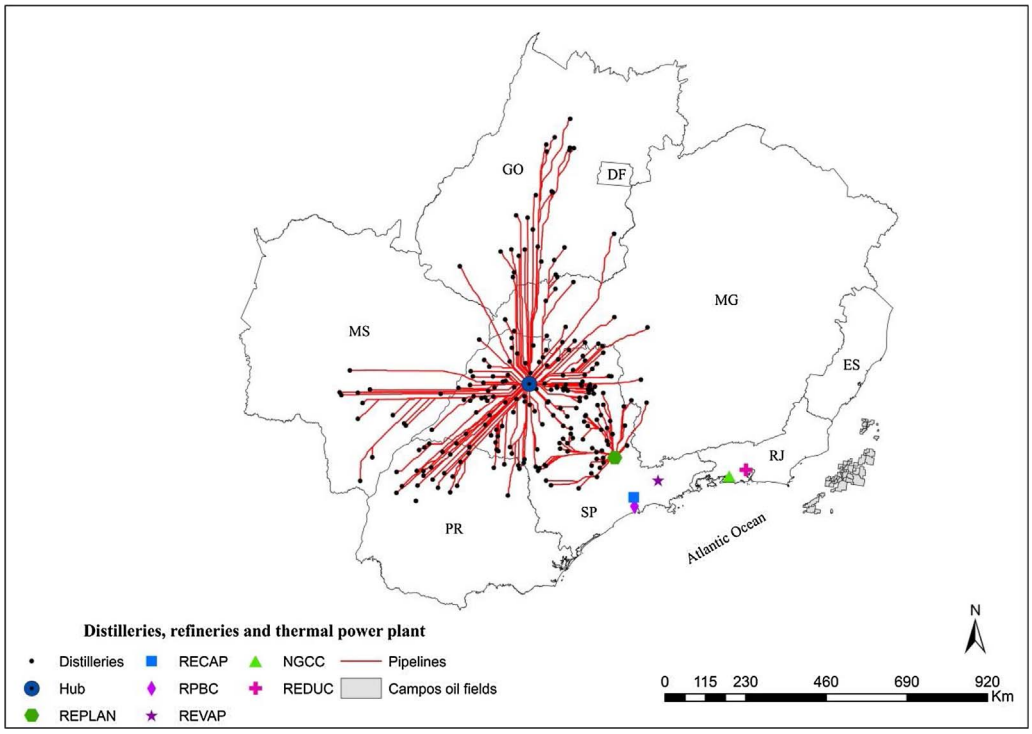

Fig. 4. Paths connecting distilleries to the hub, and distilleries to REPLAN (Cases B and C).

$$I_{RC} = (W \times 12 + 0.71) \times 10^6 \quad (10)$$

where I_{RC} is the recompression station investment costs (US$); and W is the recompression station power (MW_e).

The power required by the recompression station (W) is determined using Eq. (11) (Knoope et al., 2013).

$$W = \frac{m}{\rho} * \frac{(P_{out} - P_{in})}{n_{compressor}} \quad (11)$$

where m is the mass flow of CO_2 (kg/s); ρ is CO_2 density (kg/m^3); P_{out} is outlet pressure in the recompression station (MPa); P_{in} is inlet pressure in the recompression station (MPa); and $n_{compressor}$ represents the efficiency of the recompression station.

Inlet and outlet pressure in recompression stations were set to 8 MPa and 11 MPa, respectively (Van den Broek et al., 2010). The isentropic efficiency of the recompression station was set to 75% (Knoope et al., 2013). As defined before, CO_2 density was considered to be 800 kg/m^3 (Knoope et al., 2013).

Knowing that one compressor must be installed every 150 km path, the number of recompression stations required for the transportation of CO_2 in the designed pipeline network was determined through Eq. (12).

$$n_{RC} = INT\left(\frac{L}{150}\right) + 1 \quad (12)$$

where n_{RC} is the number of recompression stations required; and L is the length of the pipeline section.

The total investment cost results from the sum of the investment in the pipeline network and the investment in recompression stations.

- Capital recovery factor (CRF)

Capital recovery factor is calculated according to Eq. (13).

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \quad (13)$$

where CRF is the capital recovery factor (yr^{-1}); i is the annual interest rate (%); and n is the project's lifetime (yr).

Pipeline project's lifetime adopted by this study was 40 years[8] (Van den Broek et al., 2010). Discount rate was set to 10% per year (Khatiwada et al., 2016).

- Operation and maintenance costs (O&M)

Operation and maintenance costs were considered to be 3.5% of the total investment costs (including both the pipeline network and the recompression stations, and excluding energy) (Van den Broek et al., 2010).

- Variable costs (VC)

Energy consumption associated with the recompression stations was calculated through Eq. (14).

$$E = \frac{1}{\rho} * \frac{(P_{out} - P_{in})}{n_{compressor}} * \frac{10^3}{3.6} \quad (14)$$

where E is the energy consumption in recompression stations (kWh/tCO_2); ρ is CO_2 density (kg/m^3); P_{out} is outlet pressure in the recompression station (MPa); P_{in} is inlet pressure in the recompression station (MPa); and $n_{compressor}$ represents the efficiency of the recompression station.

Parameters were previously stablished for the calculation of investment costs. Applying such parameters, this study found a specific energy consumption associated with recompression stations of 1.39 kWh/tCO_2. Energy related costs or variable costs (V_C) were estimated considering both the calculated specific energy consumption, the amount of CO_2 transported (tCO_2) and electricity prices of 55.64 US $/MWh (EPE, 2016).

- Transported CO_2 (M_{CO_2})

[8] Project's lifetime of 40 years is related to the pipeline transportation network only. Carbon capture facilities have been evaluated using consistent literature data that provides capture unit projects' lifetime of 25–30 years, as previously presented in Section 2.3.

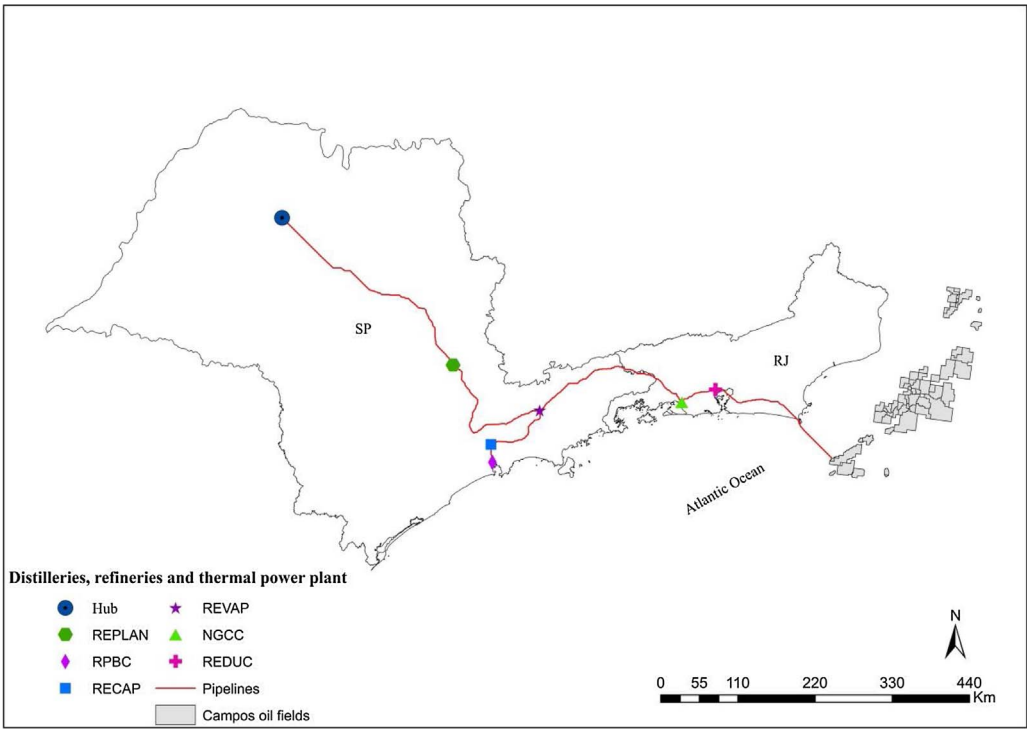

Fig. 5. Pipeline network connecting the hub to fossil-fuel sources and sink (Pitangola oil field).

The amount of CO_2 transported in each path followed the calculations previously described in Section 2.3.

Finally, by estimating total investment, O&M costs, energy costs and the amounts of transported CO_2, this study could estimate the levelized costs of CO_2 transportation using Eq. (7).

Step 3: Calculating the levelized abatement costs

The levelized abatement costs of the entire CO_2 transportation network were determined by accounting both the levelized costs of capture and the levelized costs of transportation, as established in previous steps.

3. Results

3.1. CO_2 availability and capture costs

The amount of CO_2 available for capture and the respective capture costs are presented in Table 11 and Fig. 6, for each of the emission sources analyzed in this study. The developed capture curve is displayed in Fig. 7.

Results obtained indicate that the emission source with the largest potential of contribution in terms of CO_2 availability for capture is the bagasse-fired cogeneration process in distilleries, accounting for approximately 83.0 $MtCO_2$ per year. However, costs of capture associated with this source (118.90 US$/$tCO_2$) proved to be considerably high when compared to other sources. When it comes to the selected fossil-fuel emission sources (oil refineries and power plant), the contribution potentials in an annual basis are of approximately 38% the fermentation CO_2 volume. Therefore, it is fair to say that the contribution potentials might represent an important component in enhancing the cost-effectiveness of the transportation infrastructure and might aid in improving flow regularity, especially in months when the seasonality of ethanol production provides gaps in transportation network utilization (as will be further discussed in the following sections of this study).

Table 11
CO_2 available for capture and capture costs related to the selected new emission sources.

Parameter	Fermentation	Bagasse-fired Cogeneration	FCC	HGUs	NGCC
Capture Cost (US $/$tCO_2$)	11.00	118.90	74.00	71.00	69.27
CO_2 captured ($MtCO_2$/yr)	15.70	83.00	3.23	1.46	1.24

3.2. Total abatement costs

3.2.1. Baseline case

Results indicate a levelized abatement cost for the baseline case (considering CO_2 capture from the fermentation process in distilleries) of US$ 68/tCO_2, totalizing an annual amount of 15.7 $MtCO_2$ captured and transported. Further details are fully disclosed in Silva et al. (2017).

3.2.2. Case A

Following the described methodological procedure, the results indicated a levelized abatement cost (including both capture and transportation costs) for this case enclosing only emissions sources within the selected distilleries (fermentation process and cogeneration system) of US$ 124/tCO_2, totalizing an annual amount of 98.7 $MtCO_2$ captured and transported.

Distilleries were separated in different ranges according to the respective average abatement costs and total amounts of CO_2 available for capture (Table 12). Fig. 8 provides a graphic representation of the cost ranges established for the classification of the distilleries, and the different levels of CO_2 availability.

In general, the results indicate that distilleries with low levels of CO_2 emissions and/or distilleries located far from the hub tend to present higher levelized costs of transportation. In this case, the distillery with the highest cost of transportation related to the distillery-hub path (US$ 228/tCO_2) is located 244 km away from the hub and transports approximately 12 $ktCO_2$/yr. On the other hand, the distillery with the lowest cost of transportation is located 79 km away from the hub, and transports 240 $ktCO_2$/yr. Further data on abatement costs, distance covered and quantities of CO_2 transported in each path are available at the supplementary material.

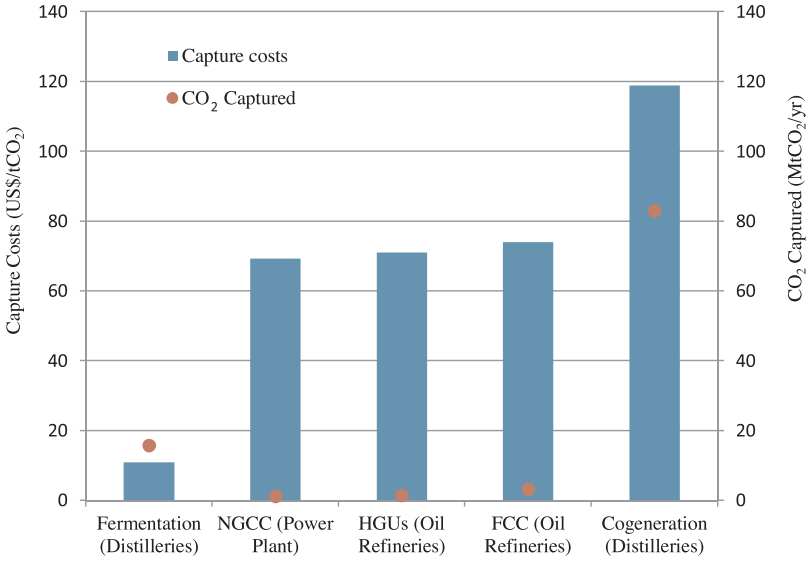

Fig. 6. Capture costs and CO_2 captured by source.

As previously outlined by this study, the inclusion of cogeneration as an alternative for enhancing carbon capture in distilleries (providing larger quantities of CO_2 for capture), does not solve the issues associated with idleness in the pipeline transportation system. The seasonal character of both ethanol and bagasse production depends on sugarcane harvest, and prohibits the continuum use of the pipeline network along the year. Therefore, in order to better understand the various levels of occupation of the pipeline network throughout the year, this study evaluated, in a monthly basis, the amounts of CO_2 captured in the selected distilleries (Fig. 9), according to the annual profile of ethanol production provided by the Brazilian Ministry of Agriculture, Livestock and Supply (MAPA, 2015). Results indicate a peak of occupation in August, and periods of idleness, especially between January and March.

3.2.3. Case B

The incorporation of new CO_2 emission sources allowed a whole new arrangement of the pipeline network, when compared to "Case A". Hence, the results obtained for each distillery diverge from the previous case, since in this case some of the distilleries are directly connected to the REPLAN oil refinery (instead of connecting to the hub). Furthermore, in this new scenario the hub is connected to the REPLAN oil refinery, instead of directly connecting to the sink (oil field). Results indicate a levelized abatement cost for this case including both distilleries (fermentation and cogeneration processes) and fossil-fuel sources (oil refineries and power plant) of US$ 126/tCO_2, totalizing an annual amount of 105.5 $MtCO_2$ captured and transported.

Table 12
"Case A" – Different ranges of costs and CO_2 captured – ethanol distilleries.

Cost Range (US$/$tCO_2$)	CO_2 Captured ($MtCO_2$/yr)
0–120	72.60
120–140	19.50
140–160	5.50
160–200	1.10
> 200	0.03
Levelized abatement cost (US$/$tCO_2$)	124.00

The levelized abatement cost includes both capture and transportation costs, and represents the average abatement cost for the whole transportation network weighted by the amounts of CO_2 transported. Table 13 presents the obtained results for all pathways, including abatement costs, amounts of CO_2 captured and transported, and length

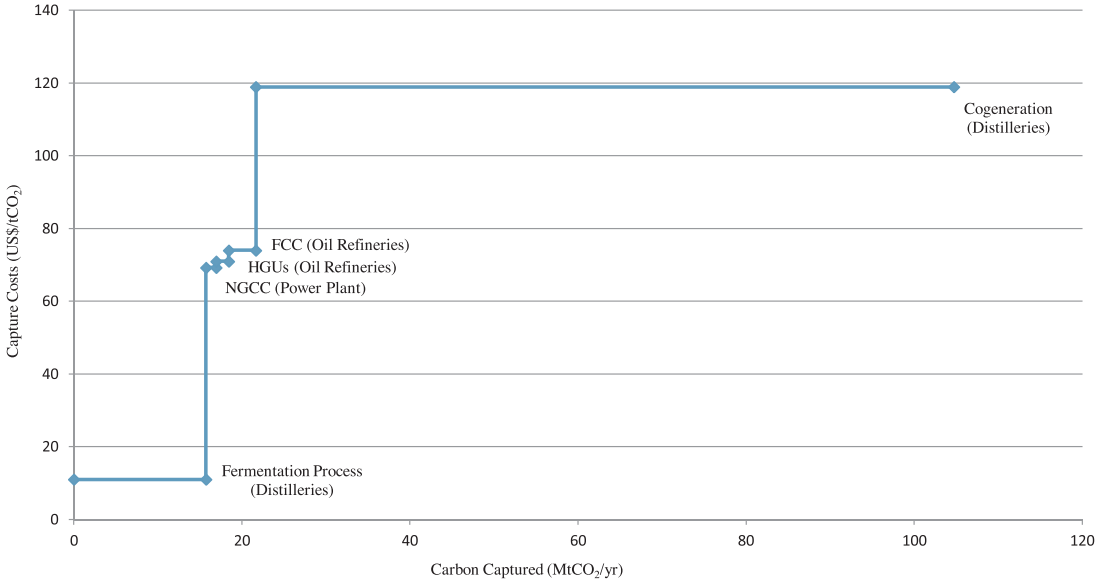

Fig. 7. Capture Curve.

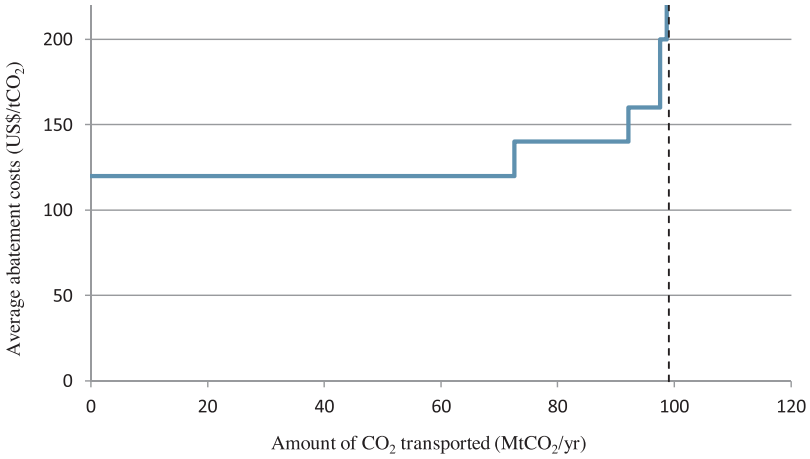

Fig. 8. "Case A" – CO_2 Supply Curve.

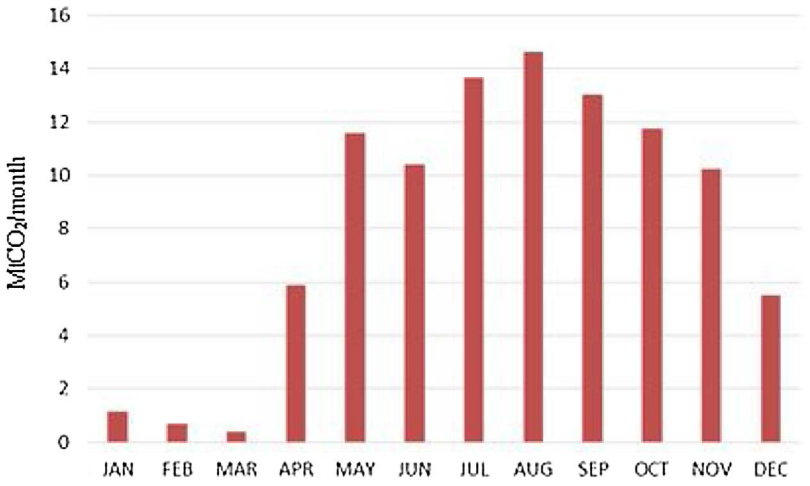

Fig. 9. "Case A" – Annual profile of CO_2 transportation and pipeline network occupation.

Table 13
"Case B" – Abatement costs, CO_2 transported and length for each considered pathway.

Pathway	CO_2 Transported ($MtCO_2$/yr)	Length (km)	Abatement Cost (US$/$tCO_2$)
Distilleries-Hub-REPLAN	82.8	352 [a,b]	119
Distilleries-REPLAN	16.0	– [b]	111
REPLAN-REVAP	100.4	231	77
RPBC-RECAP	0.8	31	89
RECAP-REVAP	2.8	111	82
REVAP-NGCC (Santa Cruz)	103.5	254	76
NGCC (Santa Cruz)-REDUC	104.8	59	70
REDUC-Field	105.2	223	77
Levelized abatement cost (US$/$tCO_2$)	126.00		

[a] Length of Hub-REPLAN pathway.
[b] Lengths for the connections of each distillery to the hub or to REPLAN are available in the supplementary material.

of each considered pathway (except for the connections of each distillery to the hub, which are available in the supplementary material).

As can be noticed, most of the CO_2 captured and transported to the sink through the designed pipeline network (around 94%) comes from the distilleries, from which cogeneration represents the main emission source (capture in the cogeneration process is approximately six times bigger than that in the fermentation process). Capture in oil refineries and in the power plant accounts for 5% and 1% of the total amount of CO_2 captured and transported to the sink, respectively. Fig. 10 displays the total amount of CO_2 annually transported in each of the considered pathways according to its origin (biogenic or fossil). Fossil-fuel CO_2 represents the amount captured in the oil refineries and in the power plant, while biogenic CO_2 represents the amount captured in the distilleries.

Transporting higher amounts of CO_2 (especially from distilleries) in the pathways connecting the oil refineries and the power plant to the sink (oil field) contributes to significantly reduce the levelized costs of transportation in these sections. Therefore, by including CO_2 emissions from bagasse-fired cogeneration, this study was able to increase the scale of the pipelines, reducing their specific costs (economy of scale). Yet, this procedure did not solve the issue of the seasonal occupation of pipelines, given the seasonal production of ethanol.

Pathways transporting only fossil-fuel CO_2 (captured in oil refineries), such as RPBC-RECAP and RECAP-REVAP, present the higher levelized costs of transportation among the new emission sources. On the other hand, when it comes to the levelized abatement costs (accounting for both capture and transportation), the capture of large quantities of CO_2 in distilleries is not enough to reduce the high abatement costs regarding the pathways connecting the distilleries to the REPLAN oil refinery (due to high costs of capture associated with the cogeneration process).

Fig. 11 shows the results obtained for costs of capture and transportation, as well as total amounts of CO_2 transported in each considered pathway, according to the designed pipeline network.

Calculated diameters for each pipeline section are presented in Table 14. The resulting values represent the theoretical diameters, or the minimum diameters required for transporting the CO_2 flow determined for each section. Such results may differ from typical values

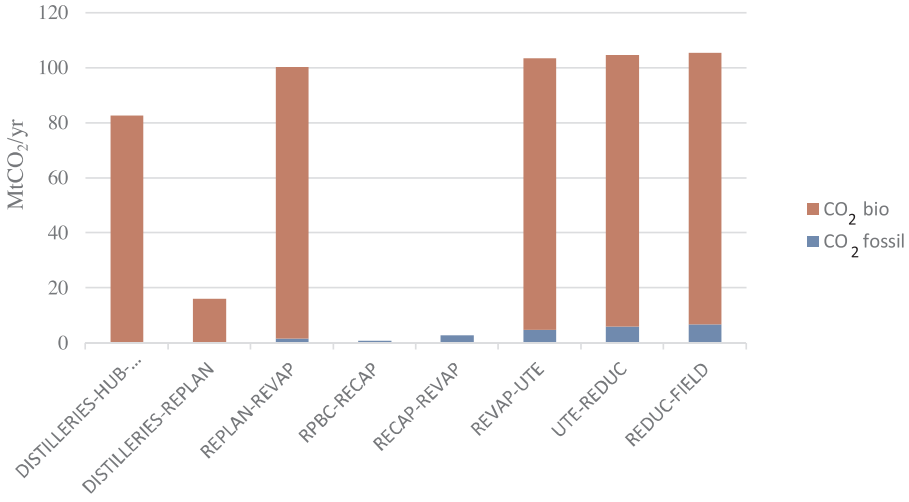

Fig. 10. "Case B" – CO_2 transported in each considered pathway, according to its origin.

observed in commercial pipelines used in gas transportation: which vary between approximately 14–28 inches (which is equivalent to 0.36–0.70 meters) (Petrobras, 2016). In this context, sections with theoretical diameters values above the normally commercialized range are operationally considered as a group of pipes with typical diameters installed in parallel, together transporting the same CO_2 flow determined for the theoretical pipe.

One of the main reasons for the inclusion of capture in fossil sources is the need to deal with idleness of the pipeline network, due to the seasonable character of ethanol production and sugarcane harvest. Therefore, given the almost annual constant production in Brazilian oil refineries (Szklo et al., 2012) and in the power generation plant equally distributed along the year,[9] an annual profile of the pipeline network occupation (Fig. 12) was elaborated (following the same criteria previously presented for "Case A", as seen in Fig. 9). Results indicate the period from January to March as the one with the lowest occupation of the pipeline network, while the period from July to September is the one with the highest occupation. March is the only month for which the amount of fossil-fuel CO_2 exceeds the amount of biogenic CO_2 in the transportation system.

Table 14
"Case B" – Theoretical diameters obtained for each pathway (pipeline section).

Pathway	CO_2 Transported ($MtCO_2$/yr)	Diameter [a](m)
Distilleries-Hub-REPLAN	82.8	1.8 [b]
Distilleries-REPLAN	16.0	0.4–1.4 [c]
REPLAN-REVAP	100.4	7.8
RPBC-RECAP	0.8	0.9
RECAP-REVAP	2.8	1.3
REVAP-NGCC (Santa Cruz)	103.5	7.9
NGCC (Santa Cruz)-REDUC	104.8	7.9
REDUC-Field	105.2	7.9

[a] Theoretical diameters.
[b] Theoretical diameter of the connection Hub-REPLAN.
[c] Range of theoretical diameters connecting distilleries to oil refinery REPLAN.

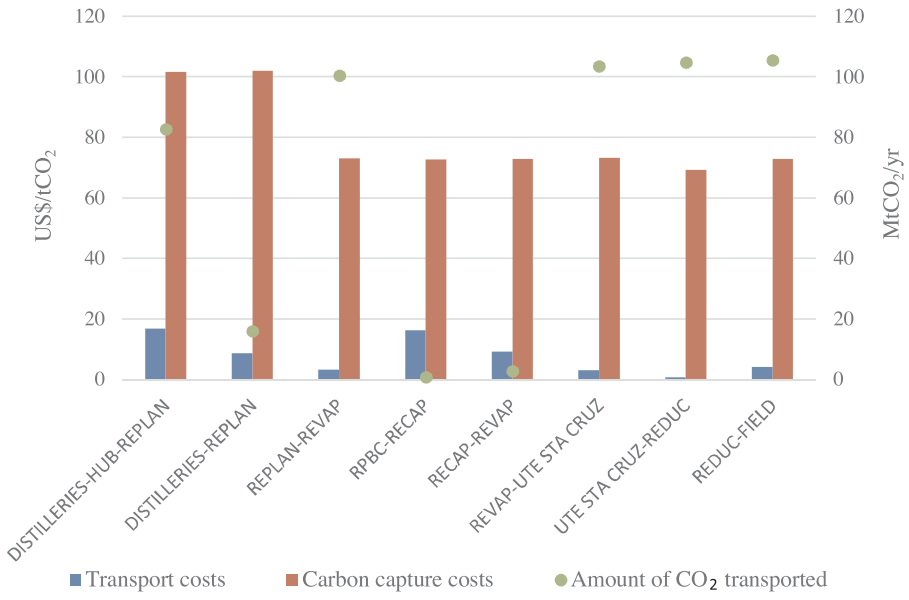

Fig. 11. "Case B" – Costs of capture and transportation, and CO_2 transported in each pathway.

3.2.4. Case C

Due to the high levelized abatement costs obtained in the previous cases for the pathways transporting CO_2 originated in the distilleries (mainly derived from the bagasse-fired cogeneration processes), "Case C" did not include into the proposed carbon transportation network the

[9] Annual CO_2 emissions in fossil-fuel sources were divided by 12, in order to equally distribute them along the year.

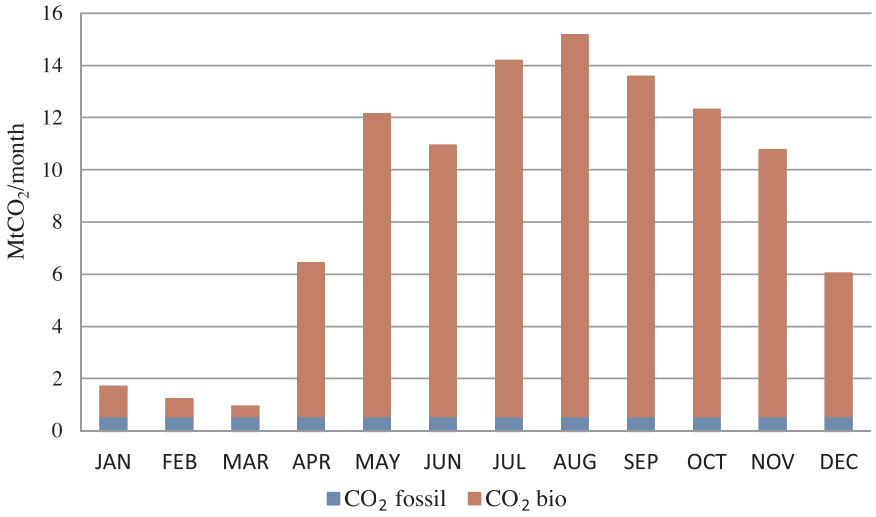

Fig. 12. "Case B" – Annual profile of CO_2 transportation and pipeline network occupation.

emission sources associated with bagasse-fired cogeneration. Such choice was driven by the significantly high costs of capture associated with these emission sources. For "Case C", the configuration of the pipeline network designed in "Case B" was maintained. Results indicated a levelized abatement cost including both distilleries (fermentation process) and fossil-fuel sources (oil refineries and power plant) of US$ 86/tCO_2, totalizing an annual amount of 22.5 MtCO_2 captured and transported.

Table 15 presents the obtained results for all pathways, including abatement costs, amounts of CO_2 captured and transported, and length of each considered pathway (connections of each distillery to hub are available in the supplementary material).

In this case, most of the CO_2 captured and transported to the sink through the designed pipeline network (around 70%) comes from the fermentation process in the distilleries. Capture in oil refineries and in the power plant accounts for 24.5% and 5.5% of the total amount of CO_2 captured and transported to the sink, respectively. Fig. 13 displays the total amount of CO_2 annually transported in each of the considered pathways according to its origin (biogenic or fossil).

Similarly to the results from "Case B", the transportation of large amounts of CO_2 from biogenic origin (or captured in the distilleries) in pathways connecting the oil refineries and the power plant to the sink (oil field) contributes to expressively reduce the corresponding levelized costs of transportation. Results obtained for the levelized costs of transportation regarding pathways for which only fossil-fuel CO_2 is transported were not altered when compared to "Case B". On the other hand, the decision to exclude CO_2 capture in the cogeneration process significantly reduced the levelized costs of transportation in the pathways connecting the distilleries to the hub or to the REPLAN oil refinery. Fig. 14 shows the results obtained for costs of capture and transportation, as well as total amounts of CO_2 transported in each pathway considered, according to the designed pipeline network.

Table 16 presents the theoretical diameters obtained for each pathway considered. As previously stated, the theoretical diameter represents the minimum diameter necessary for transporting the determined CO_2 flow in each pipeline section. But if the calculated values exceed typical commercially available sizes, this study considers a group of pipes installed in parallel and capable of meeting the demanded flow.

Once again, admitting a constant production in oil refineries and in the power generation plant equally distributed along the year, an annual profile of the pipeline network occupation (Fig. 15) was elaborated (following the same criteria previously presented for both "Case A" and "Case B"). Due to the exclusion of CO_2 captured from the cogeneration process, the contribution of fossil-fuel CO_2 to minimizing idle periods in the pipeline transportation system has become more evident. As a result, Fig. 15 indicates that in the period from January to March, when occupation of the pipeline network is relatively low, transportation of fossil-fuel CO_2 exceeds that of biogenic CO_2. Notably in March, the share of fossil-fuel CO_2 hits approximately 9 times the share of biogenic CO_2.

Table 15
"Case C" – Abatement costs, CO_2 transported and length for each considered pathway.

Pathway	CO_2 Transported (MtCO_2/yr)	Length (km)	Abatement Cost (US$/t$CO_2$)
Distilleries-Hub-REPLAN	13.3	352 [a,b]	59
Distilleries-REPLAN	2.5	– [b]	38
REPLAN-REVAP	17.4	111	82
RPBC-RECAP	0.8	231	81
RECAP-REVAP	2.8	31	89
REVAP-NGCC(Santa Cruz)	20.5	254	80
NGCC(Santa Cruz)-REDUC	21.7	59	71
REDUC-Field	22.5	223	81
Levelized abatement cost (US$/t$CO_2$)	86.00		

[a] Length of Hub-REPLAN pathway.
[b] Lengths for the connections of each distillery to the hub or to REPLAN are available in the supplementary material.

4. Discussions

Table 17 summarizes the main results of this study for each of the cases developed, as well as the results for the baseline case for reference.

Comparing the case study involving only emissions sources within the distilleries (Case A) to the reference case study (which considers capture only from the fermentation process), results indicate a significant increase in the total amount of CO_2 available for capture and transportation, due to the integration of the highly emitting cogeneration system. However, this increase in CO_2 availability is not enough to compensate for the high costs of capture associated with the cogeneration process, leading to an increase in the average levelized abatement cost. In this context, "Case A" stands as the case study with the highest levelized abatement cost.

On the other hand, of all the alternative case studies here developed, the one that presented the least levelized abatement cost was "Case C", for which only fossil-fuel sources, such as oil refineries and thermal power plant, were integrated to the system as alternative emission

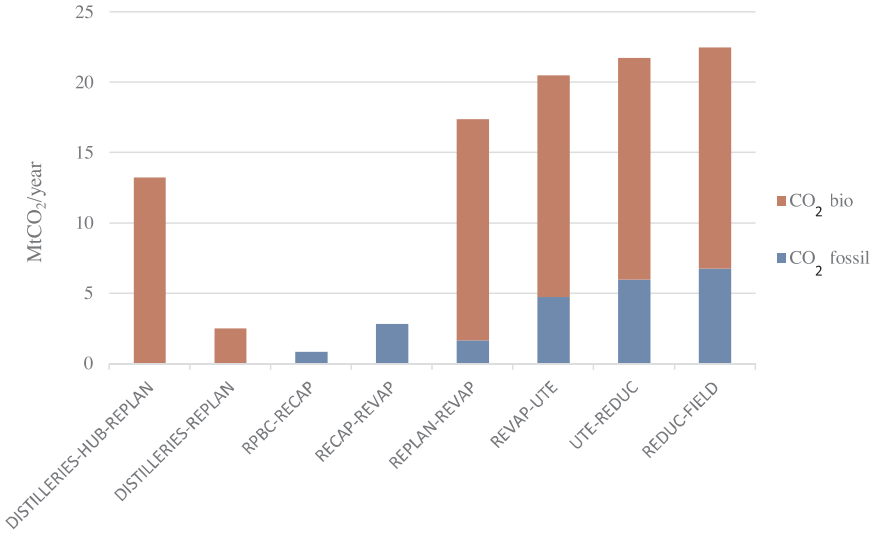

Fig. 13. "Case C" – CO_2 transported in each considered pathway, according to its origin.

sources, in detriment of the cogeneration process. This finding can be attributed to the exclusion of cogeneration systems.

As previously discussed, the importance of flow regularity throughout the pipeline transportation system is related to the need of guaranteeing capital expenditure recovery and adjusting to EOR operation characteristics, since various studies indicate it is desirable to have a continuous supply of CO_2. Overall, "Case C" is the one that most improves flow regularity throughout the year, with fossil-derived CO_2 accounting for more than 75% of the pipeline load from January through March (months in which seasonality most affects CO_2 availability).

In general, it is fair to notice that the introduction of new CO_2 emission sources, complementary to fermentative CO_2, reduces considerably the costs related to the pipeline transportation network. This could be an important result for the regulation of carbon pipeline networks, which would be based on a natural monopoly (da Costa, 2014; da Costa et al., 2015). The idea here is that the planning and operation of a carbon transportation network should not be done under a private perspective of a single sector (such as the ethanol production facilities), but under the aegis that the least-cost network can incorporate other emission sources. There are economies of scale and scope that justify the monopoly structure. In fact, one of the main challenges in the deployment of pipeline transportation systems includes guaranteeing capacity utilization and encouraging the development of integrated networks (EERC, 2011). Therefore, by lowering the average transportation cost, the implementation of the network could be eased.

Table 16
"Case C" – Theoretical diameters obtained for each pathway (pipeline section).

Pathway	CO_2 Transported ($MtCO_2$/yr)	Diameter [a](m)
Distilleries-Hub-REPLAN	13.3	0.9 [b]
Distilleries-REPLAN	2.5	0.1–0.6 [c]
REPLAN-REVAP	17.4	3.7
RPBC-RECAP	0.8	0.9
RECAP-REVAP	2.8	1.3
REVAP-NGCC (Santa Cruz)	20.5	3.9
NGCC (Santa Cruz)-REDUC	21.7	3.9
REDUC-Field	22.5	4.0

[a] Theoretical diameters.
[b] Theoretical diameter of the connection Hub-REPLAN.
[c] Range of theoretical diameters connecting distilleries to oil refinery REPLAN.

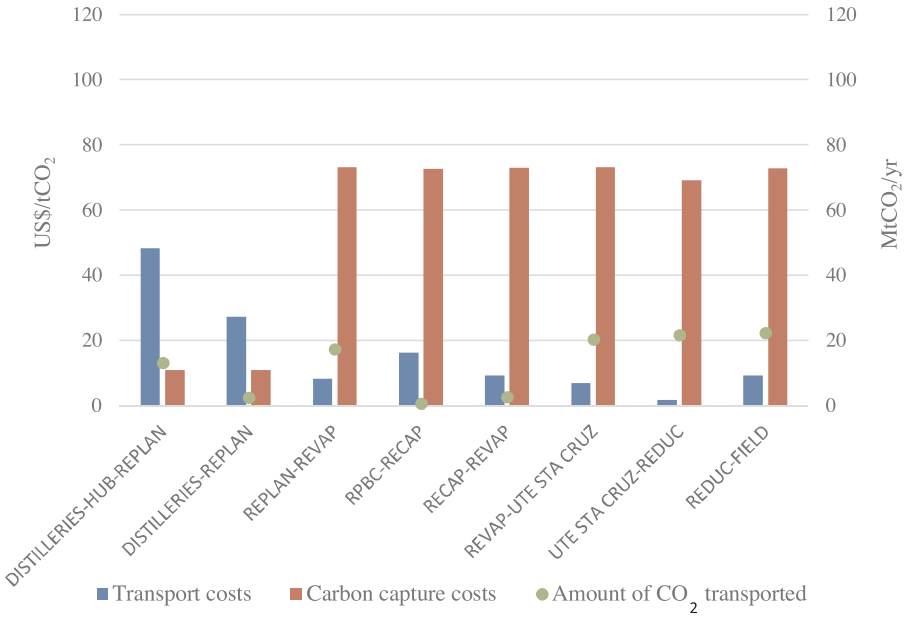

Fig. 14. "Case C" – Costs of capture and transportation, and CO_2 transported in each pathway.

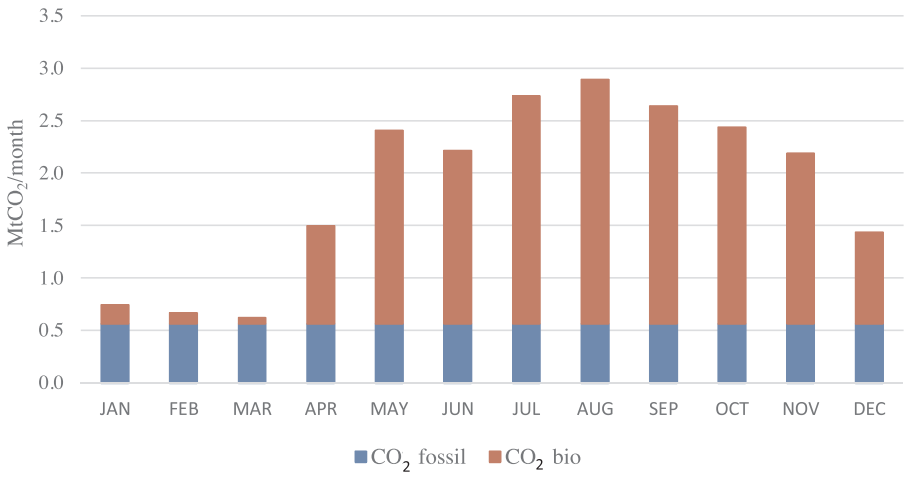

Fig. 15. "Case C" – Annual profile of CO_2 transportation and pipeline network occupation.

Table 17
Consolidated results for each case study and the reference case study.

Case study	Baseline Case	Case A[a]	Case B[b]	Case C[c]
Total available CO_2 ($MtCO_2$/yr)	15.7	98.7	105.5	22.5
Average levelized cost of capture (US$/$tCO_2$)	11	102	100	28
Average levelized cost of transportation (US$/$tCO_2$)	57	22	26	58
Average levelized abatement cost (US$/$tCO_2$)	68	124	126	86

[a] Fermentation + Cogeneration.
[b] Fermentation + Cogeneration + Fossil Sources.
[c] Fermentation + Fossil Sources.

On the other hand, the introduction of new CO_2 emission sources also increases the associated costs of capture. Even though results point towards an overall increase in the levelized abatement costs for all cases when compared to the baseline case, the integration of new emission sources improves CO_2 availability for enhanced oil recovery (EOR) to much higher levels, especially in cases involving capture in the cogeneration process. Moreover, the integration of fossil-fuel CO_2 with biogenic CO_2 is beneficial to the system due to lower costs of capture (when compared to those of the cogeneration process) and, especially, to improvements in flow regularity throughout the system, reducing idleness problems associated with the seasonality of biogenic sources.

It should be noted that other emission sources not presently contemplated by this study could be incorporated in the pipeline network, such as the cement and steel industries (among others evaluated in a study previously developed by Rochedo et al. (2016)). Furthermore, this study contemplates enhanced oil recovery (CO_2-EOR) as the storage option mostly due to technological experience, data availability and the potential economic benefits expected from the incremental oil production. However, other suitable storage options such as saline aquifers should also be taken into account, since they could represent an important opportunity to reduce costs of transportation. As a matter of fact, in further studies we aim to re-optimize the carbon transportation network by changing not only carbon sources and transportation hubs, but also carbon sinks' locations.

5. Final remarks

Final remarks concerning the obtained results are listed below.

1. CO_2 capture from ethanol fermentation is regarded as an important opportunity for BECCS deployment. However, both the seasonable character of ethanol production and disperse small-scale distilleries impose challenges for the deployment of a feasible CO_2 transportation network. In this context, alternative concepts, such as the integration of new emission sources, should be considered to address those limitations.
2. This study has demonstrated that, from an operational perspective, the incorporation of new emission sources significantly improves CO_2 availability for EOR and the integration of fossil-fuel CO_2 with biogenic CO_2 is beneficial to the system, addressing idleness problems and seasonality issues, and providing a more regular flow throughout the transportation system. Flow regularity is desirable in order to guaranteeing capital expenditure recovery and correctly adjusting to EOR operation characteristics. Of all case studies developed, "Case C" is the one that most improves flow regularity throughout the year.
3. However, from a cost perspective, this study has evaluated that, even though the incorporation of new emission sources might reduce levelized costs of transportation, it does not compensate for the increase in levelized costs of capture, resulting in higher levelized abatement costs. Nevertheless, by reducing the transportation costs the strategy adopted in this study could facilitate the development of a carbon transportation network.
4. Other possibilities for designing an optimum carbon capture transportation network could include improvements in the transportation network design, introducing alternative concepts such as the development of multiple hubs and intermodal alternatives (trucks plus pipelines). In fact, such alternatives have already been assessed by the authors in Silva et al. (2017) for the baseline case concerning capture in the fermentation process alone. Therefore, it might be interesting to evaluate such options along with the incorporation of new emission sources here assessed. Furthermore, future studies could re-optimize the carbon transportation network in order to include not only other carbon emission sources and transportation hubs, but also different storage options and carbon sink's locations.

Acknowledgements

We would like to thank the National Council for Scientific and Technological Development (Conselho Nacional de Desenvolvimento Científico e Tecnológico—CNPq) for the financial support. We also thank the UK Embassy in Brazil (through the UK Prosperity Fund) for the support for this research. We also thank the reviewers for their time and contributions to this paper.

Appendix A. Supplementary data

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.ijggc.2017.10.013.

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